BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts	**DOCKET NO. 12-035-100**

Surrebuttal Testimony of Robert Millsap

For Renewable Energy Advisors

May 29, 2013

Q. Did you file direct testimony regarding this docket on March 30, 2013?

A. I did.

Q. What is the purpose of your surrebuttal testimony?

A. I would like to follow-up on these issues, in support of rebuttal testimony by various parties.

Q. Do you agree with Sarah Wright's levelized cost-of-CO^2 assessment?[1]

A. Yes. It is easy to argue that unknown future costs are not estimable, but the Company's use of Monte Carlo simulations attempts to account for them. Because it may not be possible to estimate what the eventual outcome may be, it might be reasonable to add the possibility of no

[1] Docket 12-035-100 Rebuttal Testimony of Sarah Wright on Behalf of Utah Clean Energy May 15, 2013 pp 20-25

tax, and attach equal probabilities to each of the scenarios in Table 2[2]. The levelized avoided cost for the five scenarios with a 20% weighting applied to each, for example, would be $9.32.

Table 2. Carbon Value in $ per MWH Based on Avoided Natural Gas Generation

Discount Rate 7.154%

	BASE	HIGH	Hard Cap, Base Gas	Hard Cap, High Gas
	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2013	$0.00	$0.00	$0.00	$0.00
2014	$0.00	$0.00	$0.00	$0.00
2015	$0.00	$0.00	$0.00	$0.00
2016	$0.00	$0.00	$0.00	$0.00
2017	$0.00	$0.00	$0.00	$0.00
2018	$0.00	$0.00	$0.00	$0.00
2019	$0.00	$0.00	$0.00	$0.00
2020	$0.00	$6.13	$21.52	$25.87
2021	$0.00	$8.92	$23.05	$27.73
2022	$7.25	$11.81	$24.70	$29.70
2023	$7.61	$14.81	$26.46	$31.82
2024	$7.98	$17.91	$28.35	$34.10
2025	$8.37	$21.13	$30.37	$36.53
2026	$8.78	$22.61	$32.55	$39.14
2027	$9.21	$24.19	$34.88	$41.94
2028	$9.66	$25.89	$37.37	$44.94
2029	$10.14	$27.70	$40.05	$48.16
2030	$10.63	$29.64	$42.91	$51.60
2031	$11.16	$31.74	$46.03	$55.35
2032	$11.72	$33.99	$49.35	$59.95
Levelized value of avoided CO2 per MWH	**$3.44**	**$9.31**	**$15.37**	**$18.50**

The hard cap scenarios may seem unlikely to some, but they at least represent low-probability risks that with very significant costs. None of us believe that our homes will burn down, but we all pay for fire insurance. These are real risks to ratepayers that should not be brushed-aside. The

[2] Docket 12-035-100 Rebuttal Testimony of Sarah Wright on Behalf of Utah Clean Energy Table 2 May 15, 2013

Company considers these possibilities in their IRP, but I don't see how these risks are accounted for in the current PDDRR calculation.

Q. Do you agree with the argument that the QF contract itself protects ratepayers from these risks?

A. I agree with the notion that the contract has a certain amount of built-in protection for ratepayers. QF providers, regardless of the energy source, are locked into a contract that insulates ratepayers from small changes in fuel prices. Again, I don't understand how this value is captured in the current PDDRR calculation. It seems to me that an important issue for ratepayers may be this: if a significant tax is placed on the emissions from a carbon-based plant, the QF that relies on that fuel may be forced to shut down operations, unable to cover operating expenses with locked-in QF contract payments. This leaves ratepayers with the prospect of replacing this resource with more expensive power.

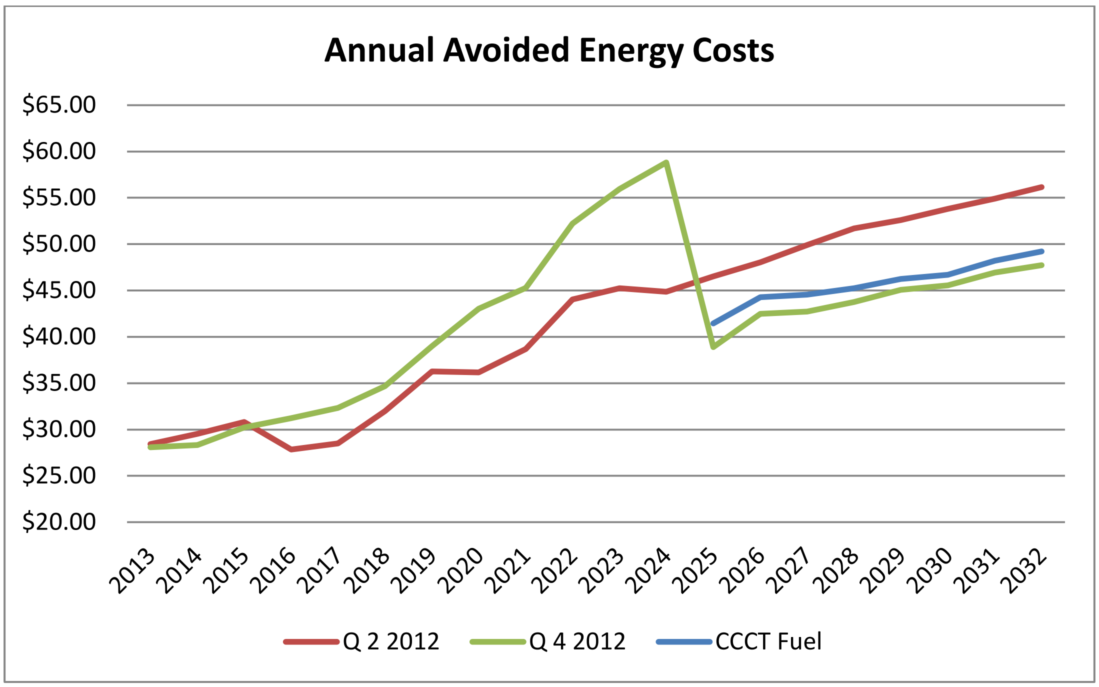
Q. But this must be a very remote possibility.

A. I don't believe so. Thinking within the PDDRR framework, the 2012 Q 4 Schedule 38 filing[3] estimates the 2026 operating costs for the 423 MW "J" plant's first full year of operation at $51.57 / MWh. This information is available from Columns C, D and H in Table 4 of the filing. Energy Strategies estimates the 2026 High Case tax on natural gas generation at $22.61 per MWh.[4] Combined operating expenses for the Company's "J" plant would be $74.18. The 2012 Q 4 51.9% Schedule 38 payment for 2026 is only $75.02. A GRID run with a realistic peak capacity figure may produce a lower payment. That's a pretty close shave, with no margin for error. Both of the hard-cap scenarios would be a disaster.

[3] Docket 12-999-01 Utah Compliance Filing 2012 Q 4 http://psc.utah.gov/utilities/misc/miscindx/1299901indx.html
[4] Docket 12-035-100 Rebuttal Testimony of Sarah Wright on Behalf of Utah Clean Energy May 15, 2013 Table 2

Q. Please review your observations about the application of GRID to avoided-cost calculations.

A. I briefly observed that GRID runs can produce highly variable results from quarter to quarter, and that the prices produced sometimes appear to be unreasonably low. The following chart[5] was provided as an example:

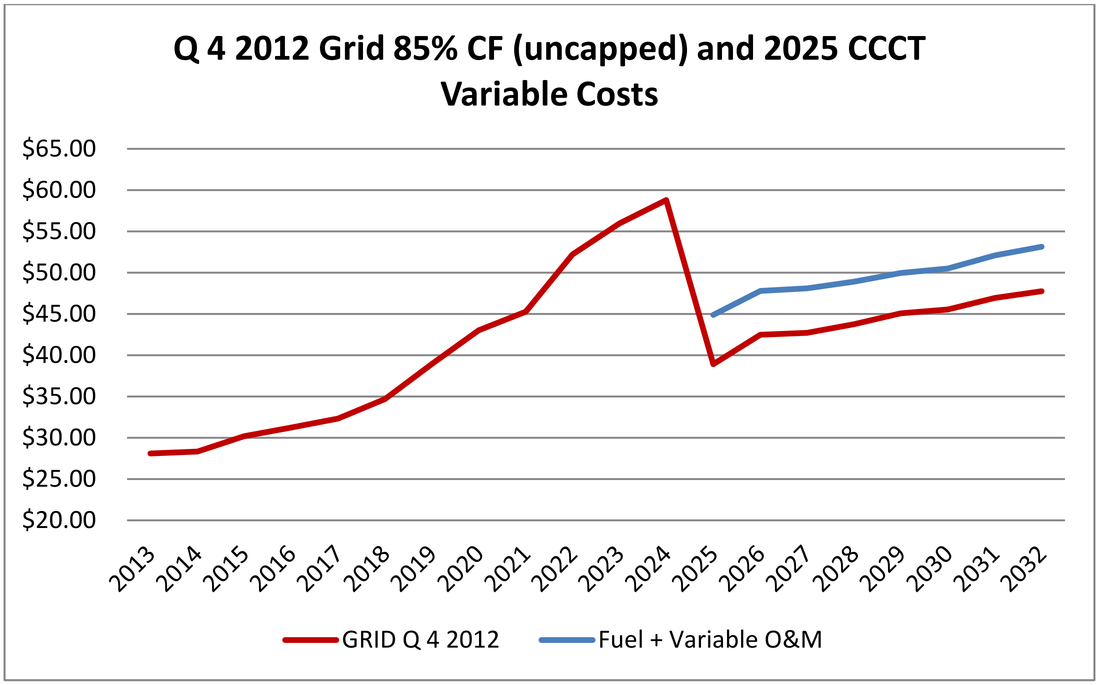


Q. Can you comment on the reference to capped energy payments made by Sarah Wright?

A. I agree with her rebuttal argument that the capped energy policy seems excessive. I should point out that the GRID costs in this chart came from Table 2 of the Q 4 filing, which is uncapped. GRID is pricing the avoided cost of energy below the fuel cost for a state-of-the-art, combined cycle plant. I would like to compare the variable costs of the combined cycle plant with GRID output in the following chart. GRID values are drawn from the “energy only” column

[5] Docket 12-035-100 Direct Testimony of Robert Millsap for Renewable Energy Advisors March 29, 2013 p 4

in 2012 Q 4 Table 1[6], and Fuel and Variable O&M costs are drawn from columns D and G of Table 4 from the same filing.



Q. Purchased power is one of the available resources in GRID calculations. How do these prices relate to wholesale prices?

A. I asked the Company to provide annual LLH Palo Verde prices in a data request. The request and the response follow:

REA Data Request 2.3

Please refer to Docket 12-035-100, testimony of Greg Duval, pages 10-14: Please provide a table, formatted similarly to Table 1, that compares the “Grid Energy Value” from column 3, Table 1, to the Palo Verde Base Case CO^2 0 and Base Case CO^2 16 LLH values for the same time period.

Response to REA Data Request 2.3

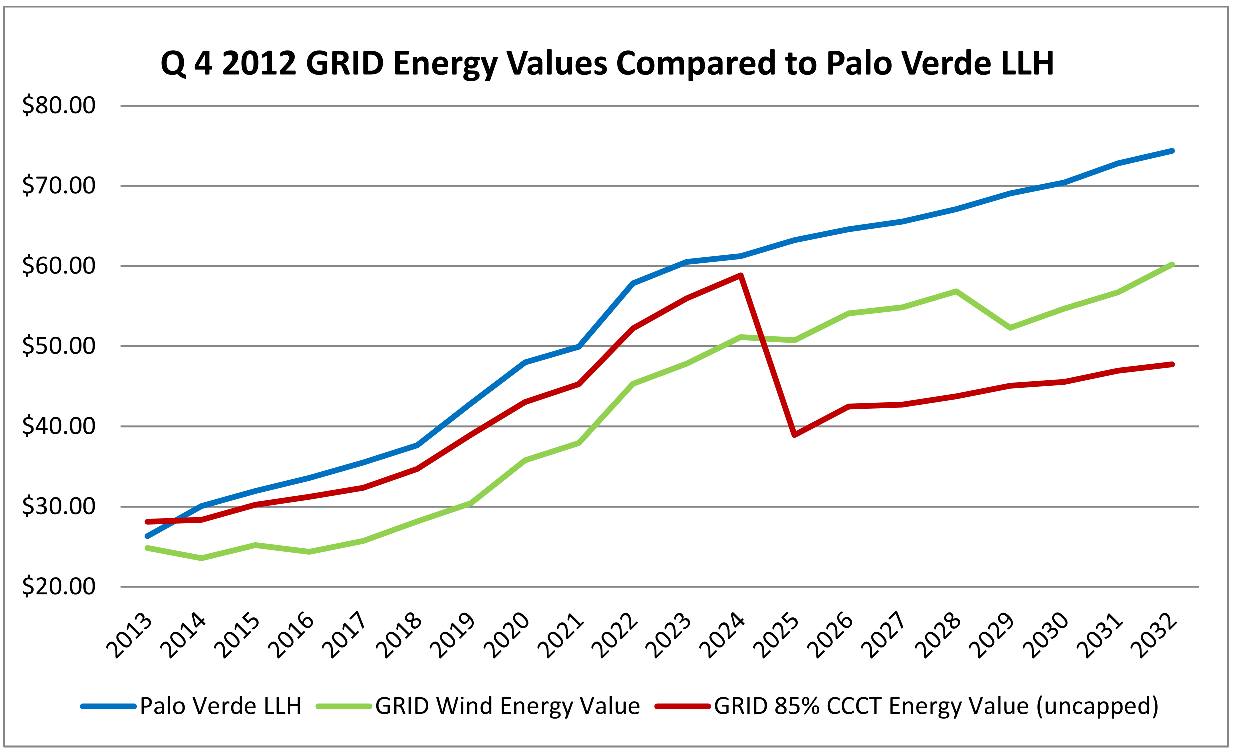
The Company objects to this request because it is unduly burdensome. As discussed in Direct Testimony of Company witness, Gregory N. Duvall, the illustrative prices provided in Table 1

[6] Docket 12-999-01 Utah Compliance Filing 2012 Q 4 http://psc.utah.gov/utilities/misc/miscindx/1299901indx.html

are intended to demonstrate the impact of resource timing on avoided cost prices. The requested studies would lower the prices in columns (3) through (5), but would not materially alter the conclusion that the Market Proxy method does not accurately account for resource timing.

Q. Why did they not answer your request?

A. I don’t believe that they understood the request. The Palo Verde LLH prices on the following chart were obtained from the 2013 IRP, on the Company’s website.[7] I don’t know the assumptions behind the curve, because they are confidential. The wind energy values are taken from column 3 of Table 1 in the Direct Testimony of Gregory Duval[8]



[7] http://www.pacificpower.net/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacTrans_SigurdToRedButte-SBT_4-30-13.xlsx

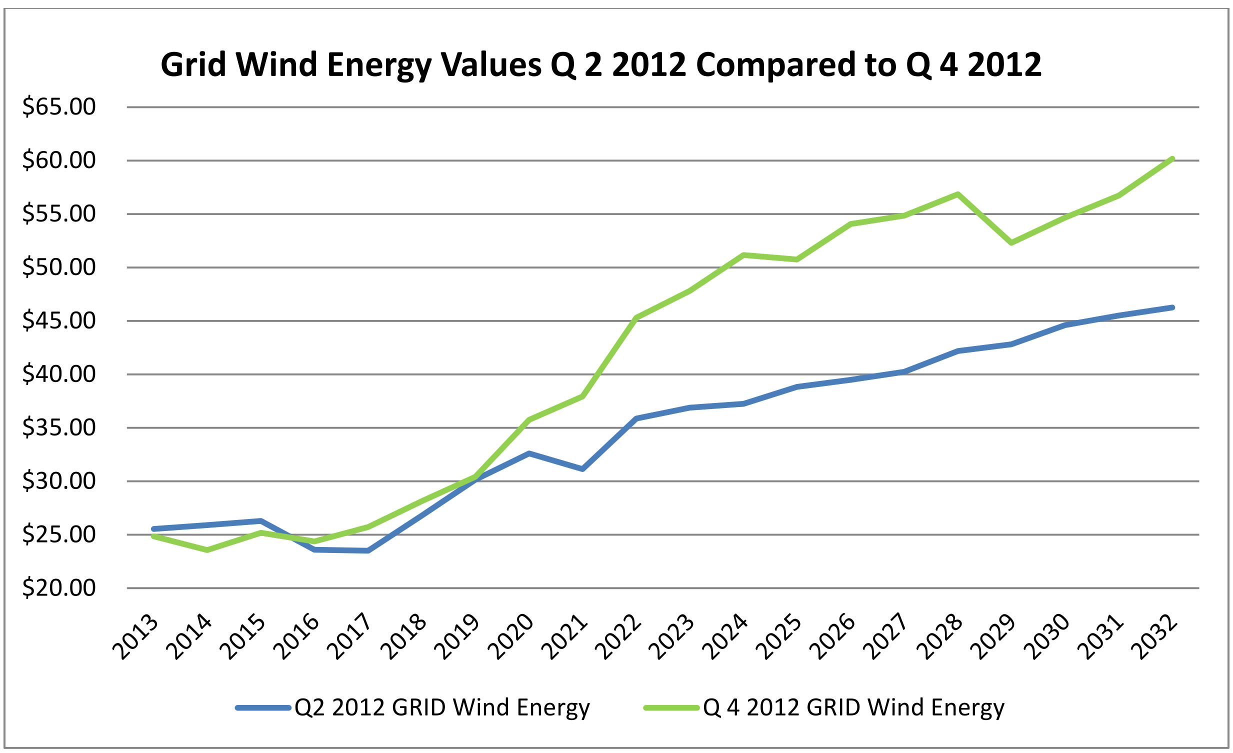
[8] Docket 12-035-100 Direct Testimony of Gregory Duvall Table 1 p 11

Q. Why are GRID prices lower than LLH prices, and why is the GRID-calculated profile for wind energy so different than the GRID calculation for the 85% CF thermal resource?

A. I'm sure that there is an explanation. I am also sure that I would not fully-understand the explanation. In any case, it appears to me that the current application of GRID as the energy component of PDDRR calculations values energy well-below expected LLH market rates.

Q. Are the Q 4 2012 Wind Energy values similar to the Q 2 2012 Wind Energy values?

A. No. The comparison is in the following chart. Q 2 values are from the Q 2 illustrative wind avoided cost worksheet[9], and Q 4 values are from the Testimony of Gregory Duvall, Table 1[10].



[9] Docket 12-999-01 Utah Compliance 2012.Q2 – Wind 80 MW and 35% Capacity Factor Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1) 6-29-212 Table 2

[10] Docket 12-035-100 Direct Testimony of Gregory Duvall Table 1 p 11

Q. What assumptions changed between Q 2 and Q 4?

A. I don't know. The amazing Q2 – Q4 change between the estimates for both thermal and wind resources illustrates their lack of value to those of us who rely on them. What assumptions changed? While filings are normally accompanied by a list of changes in assumptions, the contemplation of the effects of these changes is left to GRID. Before we have a chance to discuss the rationality of the new assumptions, the assumptions will have changed again. It does not seem reasonable to me that we should be expected to make decisions based on this information.

Q. Please comment on the continuing debate over the calculation of capacity contribution.

A. I don't believe that the data presented by the Company is relevant to wind projects in Utah. Generally, I believe that it is a mistake to attempt to determine a general capacity contribution value from a set of sites, and then to generalize the result to prospective projects with different characteristics.

Q. Please explain.

A. Every project is different. The location is obviously important. Even if the five solar sites studied were all in Utah, they would produce different results. The value of a solar array in Yakima is obviously not similar to the value of an array in Saint George. Asking ratepayers to make a decision based on a blend of these values is like asking a prospective homeowner to make a purchase based on the average home price in the Company's territory. Maura Yates clearly explains the effect of location on solar performance. [11]

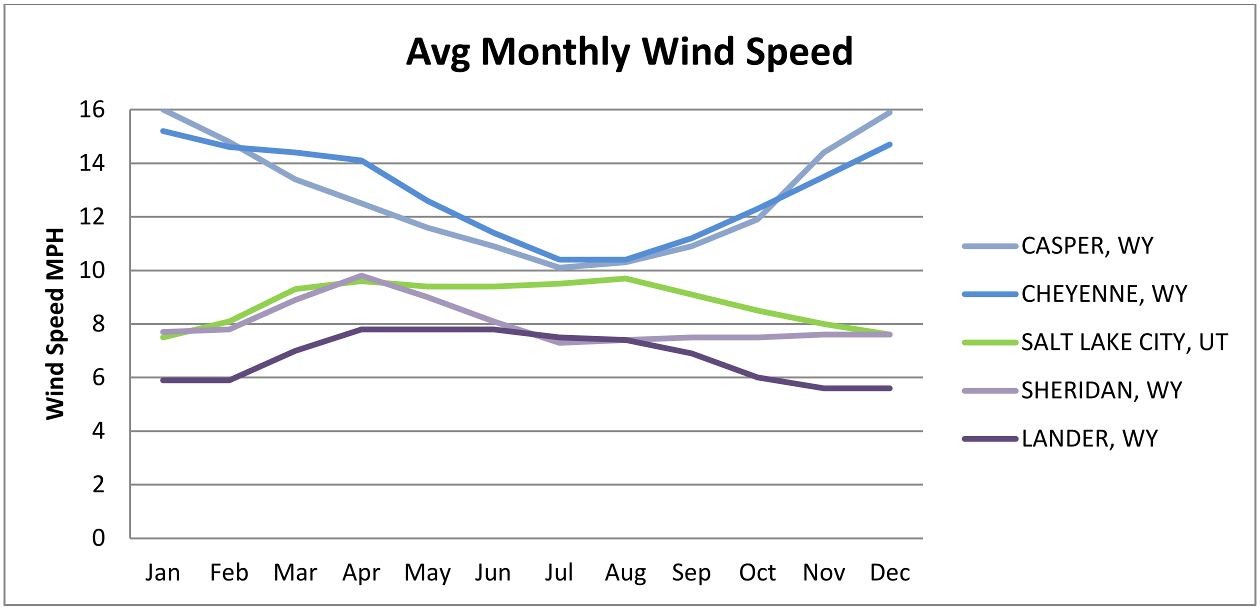
[11] Docket 12-035-100 SunEdison, LLC Comments in Response to Direct Testimony May 14, 2013

The same condition applies to wind power. The following table is the list of projects used to provide the data for the Company's wind capacity contribution study. It is borrowed from the Direct Testimony of Gregory Duvall[12]:

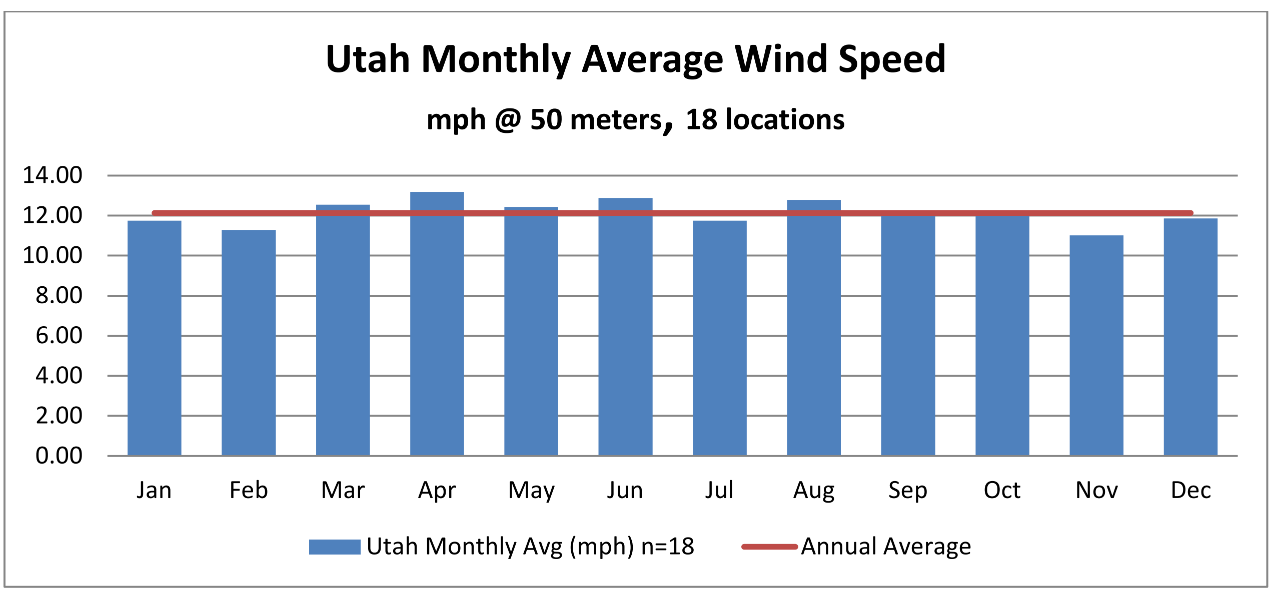
Wind Resource	COD	Type	Nameplate Capacity
Chevron Wind QF	12/1/2009	PPA	16.5
Combine Hills	12/22/2003	PPA	41.0
Dunlap I Wind	10/1/2010	Owned	111.0
Foote Creek Generation	7/21/1997	Owned	32.1
Glenrock III Wind	1/17/2009	Owned	39.0
Glenrock Wind	12/31/2008	Owned	99.0
Goodnoe Wind	5/31/2008	Owned	94.0
High Plains Wind	9/13/2009	Owned	99.0
Leaning Juniper 1	9/14/2006	Owned	100.5
Marengo 1 & 2	8/3/2007	Owned	210.6
McFadden Ridge Wind	9/29/2009	Owned	28.5
Mountain Wind 1 & 2 QF	7/2/2008	PPA	140.7
Oregon Wind Farm QF	3/31/2009	PPA	64.6
Rock River I	11/7/2001	PPA	50.0
Rolling Hills Wind	1/17/2009	Owned	99.0
Seven Mile II Wind	12/31/2008	Owned	19.5
Seven Mile Wind	12/31/2008	Owned	99.0
Spanish Fork Wind 2 QF	7/31/2008	PPA	18.9
Three Buttes Wind	12/1/2009	PPA	99.0
Threemile Canyon Wind QF	9/1/2009	PPA	9.9
Top of the World Wind	10/1/2010	PPA	200.2
Wolverine Creek	2/12/2006	PPA	64.5
		Total Wind:	**1,736.5**

Of the 1,736 Total MW Nameplate, 1,133 MW, or about 65%, is located in Wyoming. The following chart is produced from data compiled by the National Climate Data Center[13] over the past 45-73 years, depending on the site:

[12] Docket 12-035-100 Direct Testimony of Gregory Duvall Exhibit A Table 1 p 4
[13] http://www.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html



This chart should not be a surprise to anyone familiar with Wyoming winters. Many of the Company's projects are clustered around Casper. The next chart is produced from a database of anemometers on 50 ft towers, placed at prospective wind development sites in Utah, information provided by the Utah Office of Energy Development[14]. Sites from the database were selected only on the criteria that data for all twelve months of the year was available.



[14] http://www.energy.utah.gov/renewable_energy/wind/anemometerdata/index.htm

Q. Please Continue.

A. I believe that the Company's wind portfolio does not represent an accurate portrayal of wind power's normal summer capacity contribution. The charts on the following page are produced from data provided by the U.S Energy Information Administration.[15] This data is reported to the EIA by project operators. When comparing these averages, it is important to keep in mind that projects come online at various times, increasing output. These output changes can be observed in the scale changes on the left column of each chart. The timing of these additions will tend to skew the charts. Also, not all data is available for all projects. The 2012 data for Marengo and Spanish Fork II, for example, was not available. That is why I have provided the individual comparisons for three years. Information is also available on the project level, for those who wish to examine this in more detail.

Q. Is information available for Utah projects?

A. Yes, although it is obviously very limited. Because Milford II came online in the middle of 2011, and because Spanish Fork Wind II 2012 data is not available on on the EIA website, the combined state-wide production table is extremely distorted. I've constructed separate charts for each of the three projects, information obtained from the project level view at the same EIA website. Those charts follow the Wyoming and National (X-Wyoming) Charts.

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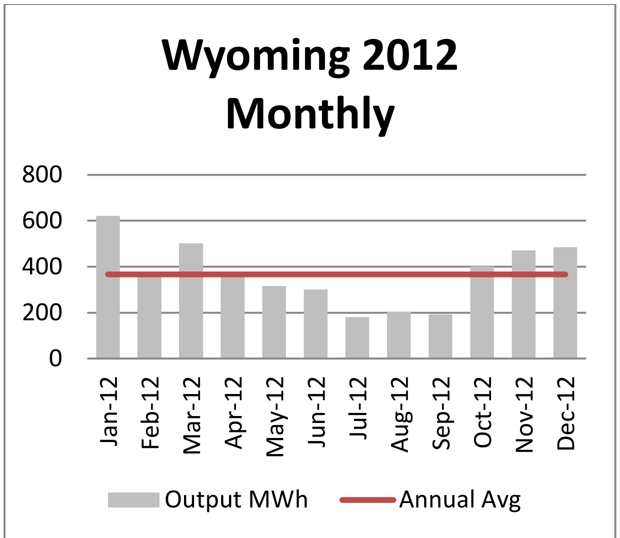
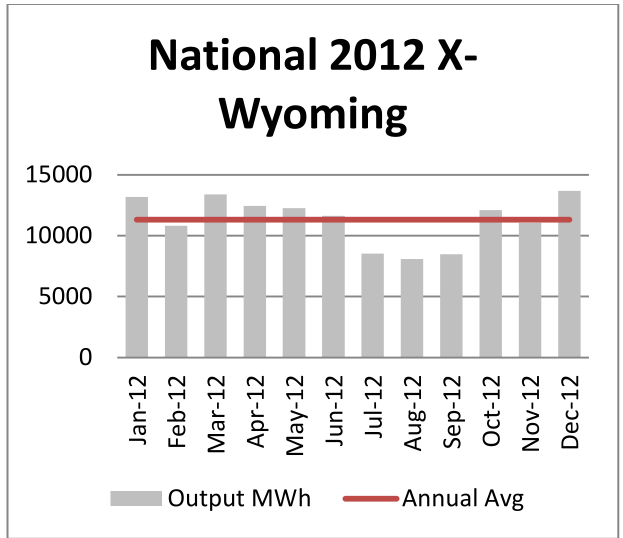
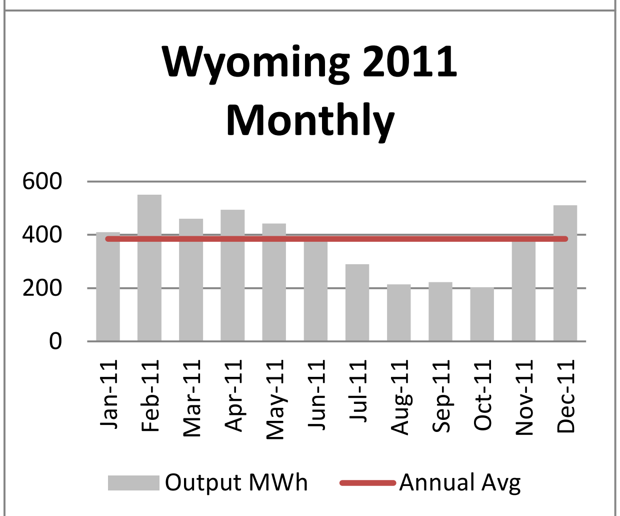
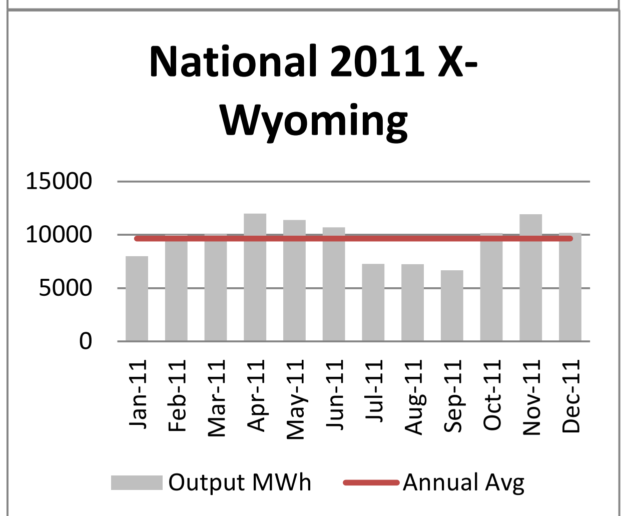
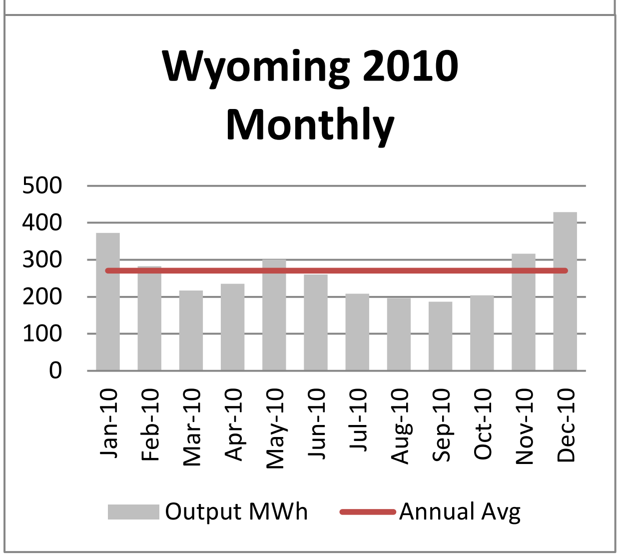
15 http://www.eia.gov/electricity/data/browser/#/topic/0?agg=1,0,2&fuel=008&geo=vvvvvvvvvvvvo&sec=o3g&linechart=ELEC.GEN.WND-US-99.M~ELEC.GEN.WND-IA-99.M~ELEC.GEN.WND-TX-99.M&columnchart=ELEC.GEN.WND-US-99.M~ELEC.GEN.WND-IA-99.M~ELEC.GEN.WND-TX-99.M&map=ELEC.GEN.WND-US-99.M&freq=M&start=200101&end=201301&ctype=linechart&ltype=pin&pin=ELEC.GEN.WND-US-99.M&rse=0&maptype=0

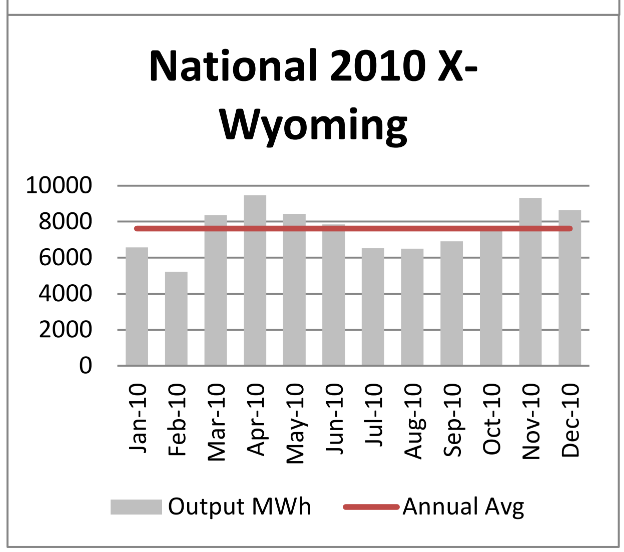

Wyoming 2012 Monthly
800
600
400
200
0
Jan-12
Feb-12
Mar-12
Apr-12
May-12
Jun-12
Jul-12
Aug-12
Sep-12
Oct-12
Nov-12
Dec-12
Output MWh
Annual Avg

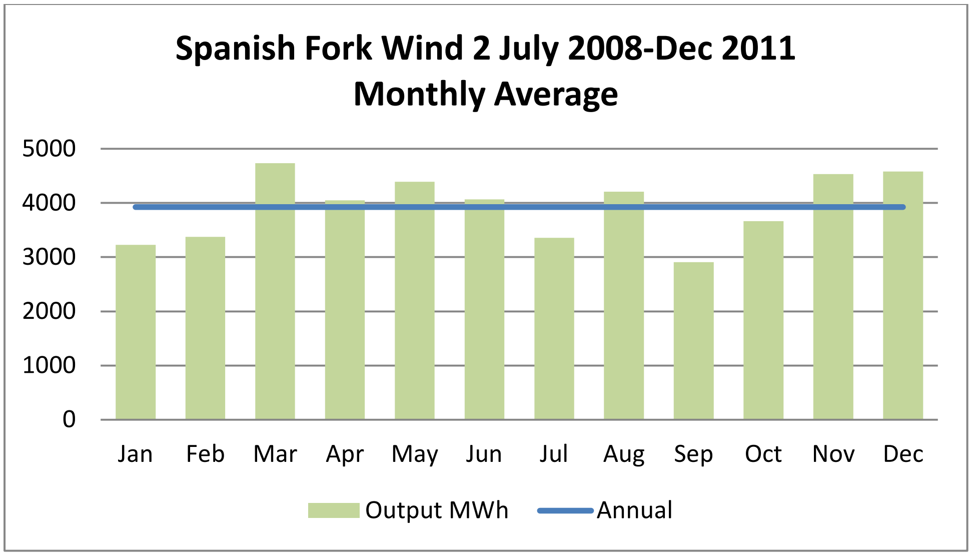

National 2012 X-Wyoming
15000
10000
5000
0
Jan-12
Feb-12
Mar-12
Apr-12
May-12
Jun-12
Jul-12
Aug-12
Sep-12
Oct-12
Nov-12
Dec-12
Output MWh
Annual Avg

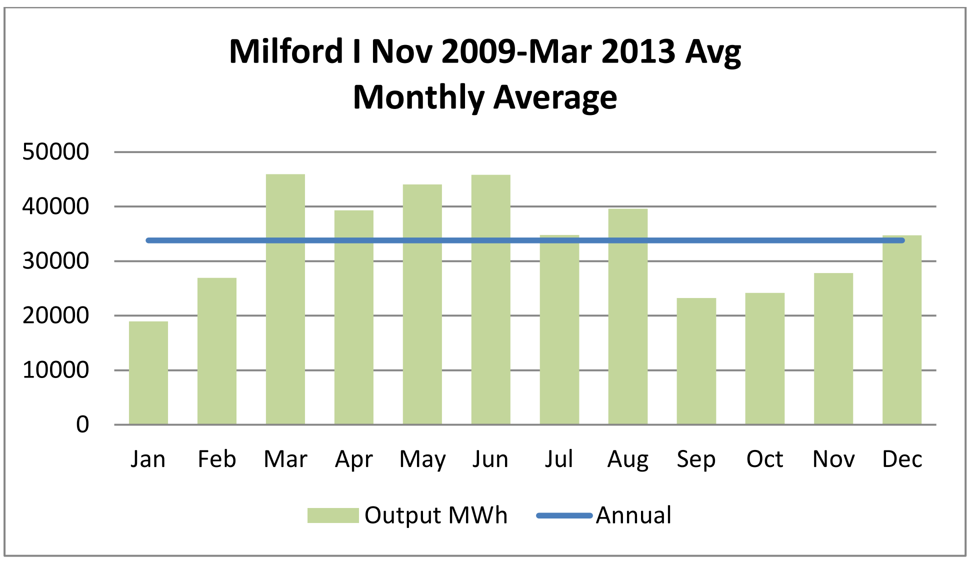

Wyoming 2011 Monthly
600
400
200
0
Jan-11
Feb-11
Mar-11
Apr-11
May-11
Jun-11
Jul-11
Aug-11
Sep-11
Oct-11
Nov-11
Dec-11
Output MWh
Annual Avg

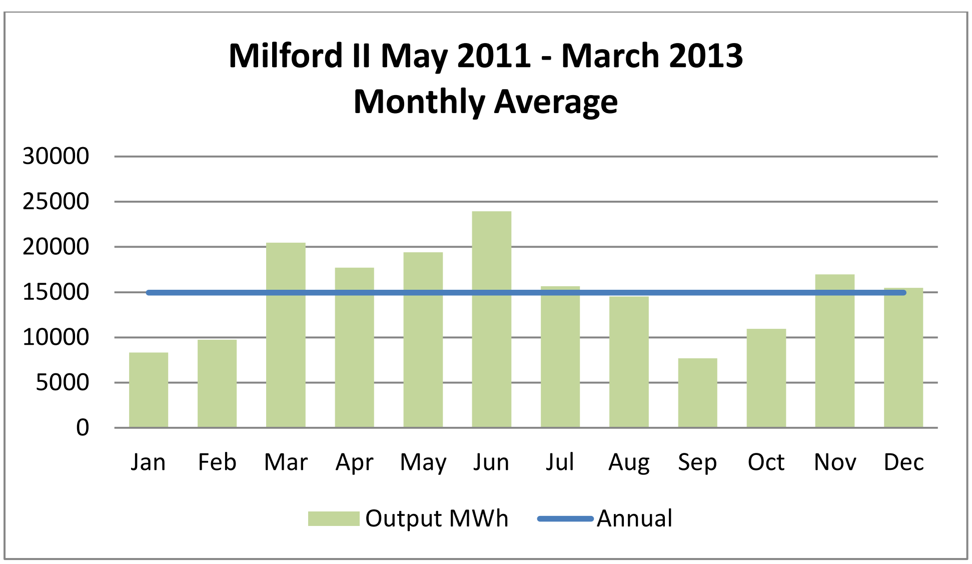

National 2011 X-Wyoming
15000
10000
5000
0
Jan-11
Feb-11
Mar-11
Apr-11
May-11
Jun-11
Jul-11
Aug-11
Sep-11
Oct-11
Nov-11
Dec-11
Output MWh
Annual Avg


Wyoming 2010 Monthly
500
400
300
200
100
0
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Output MWh
Annual Avg


National 2010 X-Wyoming
10000
8000
6000
4000
2000
0
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Output MWh
Annual Avg


Spanish Fork Wind 2 July 2008-Dec 2011
Monthly Average
5000
4000
3000
2000
1000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Output MWh
Annual


Milford I Nov 2009-Mar 2013 Avg
Monthly Average
50000
40000
30000
20000
10000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Output MWh
Annual


Milford II May 2011 - March 2013
Monthly Average
30000
25000
20000
15000
10000
5000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Output MWh
Annual

Q. Did you ask the Company for the actual monthly capacity factors for the study portfolio?

I did, in the following information request:

REA Data Request 2.1

Please refer to Docket 12-035-100, testimony of Greg Duval Exhibit A, Pages 2-4: Please provide the average combined HLH capacity factor for the wind resources used in the study, the average combined wind resource HLH capacity factors for the months of July and August, and the average number of top-100 HLH hours that occurred during July and August.

Response to REA Data Request 2.1

The heavy load hour (HLH) capacity factor for the hypothetical wind resource was 36.49 percent.

The HLH capacity factor for the hypothetical wind resource in the months of July and August was 17.32 percent.

Between 2007 and 2011, approximately 98.6 percent of the largest 100 load hours in each year occurred in the months of July and August.

Q. Why was the wind resource referred to as "hypothetical" by the Company?

A. I don't know.

Q. Please summarize your concern regarding this data.

A. In general, I believe that it is not appropriate to gather data from a location-specific, weather-related data set, and then generalize those findings to other locations. I believe that the Company's wind portfolio is not typical of wind resources around the country, and that it clearly does not represent the wind resources available in Utah. The Company's study portfolio dramatically underperforms in July and August, operating at a capacity factor (17.32%) that is less than one-half of its year-round average (36.49%). By comparison, the National (X-Wyoming) July and August MWh output for 2008-2011 was 81% of the year-round average. The three Utah projects, supported by observations from anemometers at 18 other Utah locations, appear to have summer performance that is superior to the National average. The comparisons are crude, but the differences are obvious. To clarify, I am not confusing capacity factor with capacity contribution. Any flavor of capacity contribution analysis using the Company's portfolio is bound to produce poor results. Focusing 98.6% of the analysis on the months of July and August, by framing the study as the top 100 load hours, only exaggerates the portfolio's deficiencies.

Q. What other concerns do you have about the estimation of avoided capacity costs?

A. Schedule 38 wind applicants already submit a 12 x 24 expected output matrix. This information is much more relevant to the project's capacity contribution than a value derived from other projects. The analysis should be simple enough that applicants can estimate the value themselves. If it is more complicated than that, the net effect will be that a second opaque process is added to avoided cost calculations. I believe that the current PDDRR HLH capacity factor adjustment for wind is also reasonable for solar. I would rather wrestle a bear than argue with the Division about the correct way to calculate capacity contribution; I just don't believe that any extremely sophisticated method is appropriate for Schedule 38. My understanding is that Schedule 38 was originally forged as a compromise between the Company, wishing to use GRID for the entire calculation, and QF owners offering a proxy method that is easily analyzed by all parties. I believe that resource deferral has eroded the compromise beyond reason. If the capacity calculation is changed to any complicated process that relies on Company data, assumptions and calculation, the compromise will be permanently lost.

Q. Does that conclude your testimony?

A. It does.

Submitted Respectfully,

Robert Millsap

For Renewable Energy Advisors